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Raven Energy Ltd. is engaged in the exploration, development and production of petroleum and natural gas in Alberta. Raven's current production consists of natural gas, oil and associated liquids. We will continue to focus our exploration and development activities towards natural gas. Raven's shares are listed on the Canadian Venture Exchange under the trading symbol "RVL".

At year end December 31, 2002 there were 21,028,552 common shares listed.

ANNUAL GENERAL MEETING

The Annual General Meeting of Raven Energy Ltd. will be held at the Westin Hotel, 320 - 4th Avenue SW at 10:00 a.m. on May 27, 2003

ABBREVIATIONS

ARTC: Alberta Royalty Tax Credit

bbls: Barrels

mbbls: Thousands of barrels

BOE: Barrel oil equivalent (6:1)

mBOE: Thousands of barrels oil equivalent (6:1)

mcf: Thousand cubic feet

mcf/d: Thousand cubic feet per day

mmcf: Million cubic feet

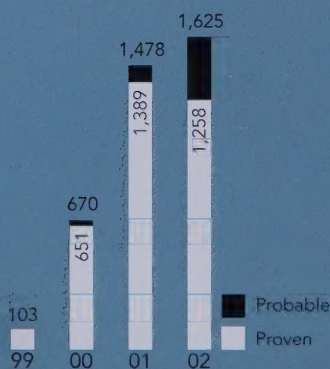
mmcf/d: Million cubic feet per day

mmbtu: Millions of British thermal units

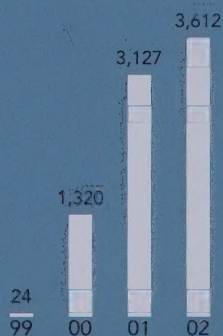
NGL: Natural gas liquids

NPV: Net present value

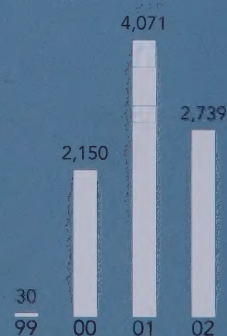
F&D: Finding and development



Reserves
(mBOE)



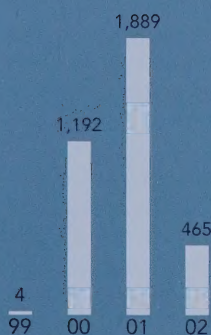
Natural Gas Production
(mcf/d)



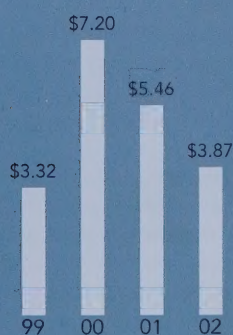
Funds Flow
(\$ Thousands)

CORPORATE HIGHLIGHTS

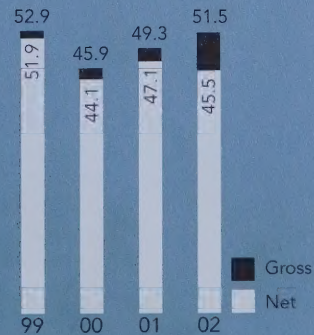
Year Ended December 31 (\$ thousands, except per share amounts)	2002	2001
Petroleum and natural gas revenue	\$ 5,298	\$ 6,228
Net income	465	1,889
Per share, basic & diluted	0.02	0.11
Funds flow from operations	2,739	4,071
Per share, basic & diluted	0.14	0.23
Net capital expenditures	5,532	7,818
Shareholders' equity	9,633	8,002
Working capital (deficiency)	(781)	549
Natural gas production (mcf/d)	3,612	3,127
NGL production (bbls/d)	18	—
Production (BOE/d)	620	521
Natural gas selling price (\$/mcf)	3.87	5.46
NGL selling price (\$/bbl)	30.18	—
Operating expenses (\$/BOE)	5.27	3.89
Cash flow netback (\$/BOE)	12.11	21.40
Proven reserves (mBOE)	1,258	1,389
Proven & probable reserves (mBOE)	1,625	1,478
F & D costs (\$/BOE) (proven & 1/2 probable)	23.63	8.11
Undeveloped land		
Net acres (thousands)	45.5	47.1
Average working interest	88%	96%
Common shares		
Weighted average (millions)	19.5	17.8
Outstanding (millions)	21.0	19.4



Net Income
(\$ Thousands)



Natural Gas Price
(\$/mcf)



Undeveloped Land Holdings
(Thousands of Acres)



We are pleased to report on the progress of our Company during 2002.

The year 2002 was one of challenges. A large swing in commodity prices occurred during the year with spot natural gas pricing averaging \$3.60 in the first quarter declining to under \$2.00 per thousand cubic feet by mid summer to a December price exceeding \$5.00. Natural gas price increases have continued into 2003. During the first quarter of 2002 the Company participated in a deep exploratory prospect at Mearon (Ladyfern) which resulted in a dry and abandoned well. These events lead to an adjustment in capital expenditures at mid year and some drilling plans were deferred to 2003. The Company continued to acquire undeveloped lands on new prospects. Raven exited the year with a modest production gain, net income, low debt and plans to accelerate drilling in established and new areas during 2003.

Raven participated in the drilling of seven gross (4.9 net) wells during 2002. This drilling resulted in 3.6 net natural gas wells, and 1.3 net dry and abandoned wells. Net capital expenditures during 2002 totaled \$5.5 million, which consisted of \$3.6 million for drilling and seismic activities, \$1.1 million for pipelines and production equipment and \$0.8 million on land expenditures. The 2002 expenditures were financed through a combination of working capital, funds from operations of \$2.7 million and \$1.5 million raised through the issuance of common shares.

Production during 2002 increased 19 percent to 620 BOE per day versus 521 BOE per day in 2001. Petroleum and natural gas revenue decreased 15 percent in 2002 as declines in commodity prices more than offset production gains. Natural gas prices declined 29 percent in 2002 to average \$3.87 per mcf versus \$5.46 per mcf in 2001. While the proven plus probable reserves in 2002 increased to 1,625 mBOE from 1,478 mBOE in the previous year, the proven component decreased from 94 percent to 77 percent. Net asset value per share remained constant for 2002 compared to 2001 at \$0.92 per share discounted at 10 percent and \$0.88 per share discounted at 12 percent.

Outlook

At December 31, 2002 Raven was well positioned for continued growth. Undeveloped land holdings within the Province of Alberta totaled 51,500 gross (45,500 net acres) at an average



88 percent working interest. At year end the Company had a working capital deficiency of \$781 thousand and an unutilized banking facility of \$3.6 million.

During the first quarter of 2003, Raven participated in the drilling of five gross (3.2 net wells). These drilling activities resulted in three gross (1.9 net) potential natural gas wells, one potential oil well and one dry and abandoned well. Completion activities are planned following spring break up to be followed by equipping and production tie-in where warranted.

An initial capital budget of between eight and ten million has been established for 2003. These expenditures will be largely financed from cash flow and existing lines of credit. Raven plans to continue exploration and development activities in east central and west central Alberta on its existing properties and will also evaluate a number of new prospects.

Raven's corporate philosophy is to grow through the drilling of exploration and development prospects. We will continue to operate the majority of the Company's production and maintain high working interests in internally generated prospects.

Our goals are consistent with previous years; to achieve higher levels of production and to provide growth in shareholder value. We would like to thank our shareholders and directors for their commitment and support.

On behalf of the Board of Directors.

Laurie Smith
President and CEO
April 14, 2003



Activity levels during 2002 were reduced compared to the previous year. Production increases were more than offset by lower natural gas prices resulting in decreased funds from operations compared to 2001. Drilling activities were scaled back accordingly and several projects were deferred to 2003. Raven concentrated its efforts on development activities in the Viking natural gas production area and on exploratory projects in west central and northern Alberta.

Capital expenditures for the year totaled \$5.5 million as compared to \$7.8 million in 2001. Capital expenditures for 2002 included \$3.6 million for drilling and seismic activities, \$1.1 million in pipelines and facilities costs and \$0.8 million on land expenditures. Raven participated in the drilling of seven gross (4.9 net) wells during 2002. This drilling resulted in five gross (3.6 net) natural gas wells and two gross (1.3 net) dry and abandoned wells. A deep exploratory well drilled in the first quarter of 2002 at Mearon (Ladyfern) was abandoned. A well (60% working interest) drilled in the Fir area was completed as a potential natural gas well. Late in the year, an existing wellbore (75% working interest) in the Bigstone area was re-entered and subsequently completed as a potential shut-in natural gas well. Both of these shut-in natural gas wells are lower productivity wells and are being evaluated for tie-in to production facilities.

In the Viking area, four wells were drilled. Three of the wells were subsequently completed as natural gas wells. Two of these wells were placed on production in the latter part of 2002 and the third commenced production in January 2003. Raven also carried out an active recompletion program in 2002 to maximize production in the Viking area. Additional recompletion activities are planned in 2003.



Production during 2002 increased to 620 BOE per day compared to 521 BOE per day in 2001. Production was comprised mainly of natural gas, which averaged 3.6 mmcf per day. Production was derived from three properties being Viking, Edson and Robin. Proven plus probable reserves increased to 1,625 mBOE from 1,478 for the previous year. Finding and development costs in 2002 were \$23.63 per BOE based on proven plus one half probable reserves. Although the Company had additions of 724 mBOE, this was offset by negative revisions of 351 mBOE resulting in an unsatisfactory finding and development cost for 2002. The average three-year finding cost remained a more reasonable \$9.10 per BOE.

Cash flow netbacks for 2002 were reduced to \$12.11 per BOE from \$21.40 per BOE in 2001 mainly due to lower commodity pricing. Operating expenses were \$5.27 per BOE in 2002 compared to \$3.89 in 2001 with the majority of the costs being third party processing and operating fees.

Although 2002 was a year of reduced drilling activity, with modest reserve gains, Raven continued its strategy of developing high working interest prospects in west central and east central Alberta. Several larger blocks of undeveloped lands located in west central Alberta were acquired at crown land sales. Additional lands were earned through farm-in agreements with industry third parties. Drilling activity in 2003 is planned at Ante Creek and Goose River where the Company acquired undeveloped land positions during 2002. Raven will continue to drill select natural gas prospects in east central Alberta as well as deeper natural gas and light oil prospects in west central Alberta.



West Central Alberta

Raven (90% interest) completed a re-entry of an existing wellbore in the Edson area, and placed the well on production as a dual zone natural gas producer in the first quarter of 2002. Production rates from this well during the year were lower than anticipated with current production approximately 550 mcf per day and 15 bbls per day of NGL. A 2,300 meter well drilled in the Fir area, (60% interest), was completed as a lower productivity natural gas well and may be tied in during the second half of 2003. Raven (75% interest) completed the re-entry of another existing wellbore in the Bigstone area late in 2002 resulting in an additional shut-in natural gas well with low productivity.

The Company continues to search for opportunities in west central Alberta. Several 1,500 meter Mannville test wells, targeting natural gas, are planned for later in

the year on a seven section block of land (50% interest) in the Goose River area. At Ante Creek, Raven acquired five sections of 100% interest land late in 2002. In early 2003, the Company placed a Triassic oil well located on these lands on production. A delineation well was drilled offsetting this well in March 2003 and is awaiting completion. Further activities are planned in 2003 for this 100% interest property.

Other lands have been acquired at Sturgeon, Goodwin and Eureka in north and west central Alberta. These prospects will be further evaluated with seismic where applicable, and scheduled for drilling, if warranted, in the latter part of 2003 or early 2004. Although the results from the initial natural gas prospects drilled and re-entered in west central Alberta have not met expectations, Raven believes that it can build its production in this area by continuing to target liquids rich, sweet natural gas prospects at depths to 2,800 meters.

East Central Alberta

The Viking area continues to be Raven's largest producing area. During the year the Company participated in the drilling of four wells, resulting in three producing natural gas wells (75% interest) and one dry hole (92% interest). Raven has an interest in 17 gross (11.9 net) producing natural gas wells in this area. In 2002 Raven reworked wells on a continuing basis to maintain production by perforating new natural gas zones, commingling existing zones in several wells and adding field compression where necessary.

In 2002 net daily natural gas production averaged 2.52 mmcf per day compared to 2.87 mmcf per day in 2001. In the first quarter of 2003, Raven drilled one potential natural gas well (92% interest). The well is scheduled for completion and production tie-in after spring break up. Further wells are planned for the Viking area to add production to offset declines and utilize existing infrastructure.

In the Beaverhill Lake area the Company drilled two wells (50% interest before payout; 70% interest after payout) in early 2003 targeting shallow natural gas prospects similar to those in the Viking area. The wells will be completed during the second quarter, and tied in for production during the second half of the year. Additional drilling is also planned for this area during 2003.

Reserves Summary

Sproule Associates Limited of Calgary evaluated Raven's petroleum and natural gas reserves as of January 1, 2003. The following table outlines the estimated reserves and discounted cash values before taxes. These reserves are the Company's gross reserves before royalties using an escalated pricing forecast. Probable reserves were not risked in the Sproule report. Estimated capital costs of \$959,000 are required to place the proven non-producing and the proven undeveloped reserves on production.

Date of Evaluation	Reserve Category	Natural Gas (mmcf)	Oil & NGL (mbbls)	BOE (mbbls)	10% NPV (\$000s)	12% NPV (\$000s)
January 1 2001	Proven developed producing	2,799	–	467	7,770	7,496
	Proven developed non-producing	562	–	94	769	698
	Proven undeveloped	542	–	90	1,890	1,836
	Total proven	3,903	–	651	10,429	10,030
	Probable developed	113	–	19	171	166
	Total proven & probable	4,016	–	670	10,600	10,196
January 1 2002	Proven developed producing	4,753	–	792	8,515	8,092
	Proven developed non-producing	582	–	97	795	712
	Proven undeveloped	2,587	69	500	5,676	5,266
	Total proven	7,922	69	1,389	14,986	14,070
	Probable developed	535	–	89	576	498
	Total proven & probable	8,457	69	1,478	15,562	14,568
January 1 2003	Proven developed producing	4,682	15	795	10,284	9,872
	Proven developed non-producing	621	–	104	956	903
	Proven undeveloped	1,339	136	359	5,116	4,883
	Total proven	6,642	151	1,258	16,356	15,658
	Probable developed	775	10	139	1,382	1,278
	Probable undeveloped	335	172	228	2,492	2,282
	Total proven & probable	7,752	333	1,625	20,230	19,218

Sproule Report Price Forecast

Year	Crude Oil		Natural Gas	
	WTI Cushing Oklahoma (\$US/bbl)	Edmonton Par Price (\$/bbl)	Alberta Plantgate Index (\$/mmbtu)	Henry Hub Price (\$US/mmbtu)
2003	25.99	38.43	5.72	4.39
2004	23.60	34.82	5.21	4.05
2005	21.63	32.22	4.60	3.61
2006	21.96	32.78	4.27	3.40
2007	22.29	33.90	4.42	3.45
2008	22.62	34.42	4.48	3.50
2009	22.96	35.58	4.67	3.56
2010	23.31	36.13	4.75	3.61
2011	23.66	36.69	4.84	3.66
2012	24.01	37.26	4.94	3.72
2013	24.37	37.83	5.03	3.77
2014	24.74	38.42	5.12	3.83

Thereafter: Escalation rate of 1.5%

The following table summarizes Raven's reserves with additions and revisions.

	Natural Gas (mmcf)		Oil & NGL (mmbbls)		BOE (mmbbls)
	Proven	Probable	Proven	Probable	Proven & probable
January 1, 2001	3,903	113	—	—	670
Additions	5,083	535	69	—	1,005
Production	(1,141)	—	—	—	(190)
Revisions	77	(113)	—	—	(7)
January 1, 2002	7,922	535	69	—	1,478
Additions	2,080	430	134	172	724
Production	(1,318)	—	(6)	—	(226)
Revisions	(2,042)	145	(46)	10	(351)
January 1, 2003	6,642	1,110	151	182	1,625

Raven's proven plus probable reserves increased from 1,478 mBOE to 1,625 mBOE at January 1, 2003. Reserve additions of 724 mBOE were offset by a negative reserve revision of 351 mBOE, mainly at Edson and Robin. The largest reserve revision was recorded at Edson where a natural gas well with proven undeveloped reserves of 2,035 mmcf at December 31, 2001 was placed on production in early 2002. Production performance for the Edson well was less than forecast resulting in a negative revision for proven natural gas reserves. After production of 276 mmcf of natural gas in 2002, proven developed producing reserves of 640 mmcf and probable developed reserves of 331 mmcf were booked for the property at year end 2002. At Robin, natural gas production performance based on decline analysis reduced the proven developed reserves by 438 mmcf with 107 mmcf of that revision reclassified to probable developed reserves.

Land Summary

Undeveloped land expenditures in 2002 were approximately \$800,000. The Company acquired 17,792 net acres of Alberta land at an average price of \$43.50 per acre. An additional 3,520 net acres were acquired by way of farm-in agreements with industry third parties. A total of 440 acres were purchased and 2,540 acres were sold to industry third parties.

Raven believes that a large undeveloped land base is essential for ongoing growth. The Company maintains high working interests in its undeveloped land holdings, all of which are within Alberta. Raven's undeveloped land position at year end was 51,515 gross (45,500 net) acres with an average working interest of 88 percent. Significant portions of Raven's undeveloped land holdings are located in west central Alberta.

The following table outlines Raven's land position as of December 31, 2002.

Undeveloped Land Holdings (acres)	Gross	Net	Working Interest
December 2001	49,320	47,112	95.5%
December 2002	51,515	45,500	88.3%

An independent evaluation as of December 31, 2002 appraised Raven's undeveloped land holdings at \$1,926,160.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis should be read in conjunction with the audited financial statements for the year ended December 31, 2002. Where amounts are expressed on a barrel of oil equivalent basis (BOE), natural gas volumes have been converted to barrels of oil at six thousand cubic feet per barrel.

The following table provides summaries of Raven's operations for the past two years:

Operations Summary

	2002			2001		
	\$000's	\$/BOE	%	\$000's	\$/BOE	%
Petroleum and natural gas revenue	5,298	23.43	100.0	6,228	32.74	100.0
Royalties	1,060	4.69	20.0	1,424	7.49	22.9
Alberta Royalty Tax Credit	(98)	(0.43)	(1.8)	(146)	(0.77)	(2.3)
Operating costs	1,192	5.27	22.5	740	3.89	11.9
Field netback	3,144	13.90	59.3	4,210	22.13	67.5
General and administrative – gross	468	2.07	8.8	351	1.85	5.6
General and administrative – recoveries	(121)	(0.53)	(2.3)	(155)	(0.82)	(2.5)
Current taxes	5	0.02	0.1	5	0.02	0.1
Operating netback	2,792	12.34	52.7	4,009	21.08	64.3
Cash interest	53	0.23	1.0	(62)	(0.32)	(1.0)
Funds flow from operations	2,739	12.11	51.7	4,071	21.40	65.3
Stock based compensation	3	0.01	0.1	–	–	–
Depletion and depreciation	2,239	9.90	42.2	1,286	6.76	20.7
Future income taxes	32	0.14	0.6	896	4.71	14.4
Net income	465	2.06	8.8	1,889	9.93	30.2

Petroleum and natural gas revenue decreased 15 percent to \$5.3 million in 2002 due to decreased natural gas prices. Production increased 19 percent to average 620 BOE per day in 2002 compared to 521 BOE per day in 2001. Increases in production were derived mainly from the Edson area as well as the impact of a full year production from the Robin area. Natural gas production increased 16 percent to average 3,612 mcf per day in 2002 (3,127 mcf per day in 2001). New production from the Edson area contributed 18 BOE per day of natural gas liquids in 2002. Production will continue to increase in 2003 with the addition of new production from the west central and east central Alberta areas.

Production gains were more than offset by a decline in the average natural gas price realized. The average sales price received declined 28 percent from \$32.74 per BOE in 2001 to \$23.43 per BOE in 2002. This decline was the result of natural gas prices, which decreased 29 percent to average \$3.87 per mcf in 2002 (\$5.46 per mcf in 2001). The Company enters into physical contracts for the sale of natural gas at fixed prices and terms to manage fluctuations in commodity prices. Petroleum and natural gas revenue in 2002 included losses of \$279,000 (\$0.21 per mcf) on such transactions. Currently, the Company has contracted an average of 2.1 mmcf per day for the period from April 1 to October 31, 2003 at an average price of approximately \$6.15 per mcf. The Company has not contracted any natural gas liquids or oil.

Royalties, net of ARTC, on a barrel of oil equivalent basis, decreased 37 percent to \$4.26 from \$6.72 in 2001. This decrease resulted from the combination of a crown royalty holiday at Edson and lower natural gas prices. On a margin basis, gross royalties decreased from 22.9 percent to 20.0 percent in 2002 while ARTC received declined 0.5 percent to 1.8 percent in 2002. The Company currently receives ARTC on all its crown royalties, however, on a production unit basis, ARTC declined from \$0.77 per BOE in 2001 to \$0.43 per BOE in 2002 due to the impact of the crown holiday production. Royalties are expected to increase in 2003 due to the expiry of the crown royalty holiday at Edson.

Operating costs increased 35 percent from \$3.89 per BOE in 2001 to \$5.27 per BOE in the current year. Operating costs have increased over the prior year due to higher maintenance and compression costs, minor workover expenses and higher third party processing and compression fees on new production. Operating costs will remain relatively unchanged in 2003 due to a similar cost structure being anticipated.

General and administrative expenses, before overhead recovered by the Company as operator, increased from \$1.85 per BOE in 2001 to \$2.07 per BOE in 2002 due mainly to additional office space acquired late in 2001 and additional administrative staff. Overhead recovered by the Company from drilling and construction activities decreased in 2002 in accordance with activity. General and administrative expenses, net of overhead recovered, increased from \$1.03 per BOE in 2001 to \$1.54 per BOE in 2002. Modest increases are expected in general and administrative expenses in 2003, however expenses on a production unit basis are expected to decrease with increased production.

Current taxes are composed entirely of the federal Large Corporation Tax on capital as the Company is not currently taxable on income and does not have any operations outside of Alberta. Interest expense, net of interest income, of approximately \$53,000 was incurred utilizing the banking facilities at various times during 2002 and resulted in a charge of \$0.23 per BOE. In 2001, interest income was earned on cash balances throughout the year, contributing \$0.32 per BOE.

Funds flow from operations decreased 33 percent to \$2.7 million from \$4.1 million in 2001. On a barrel of oil equivalent basis, funds flow from operations decreased 43 percent from \$21.40 per BOE in 2001 to \$12.11 per BOE in 2002. Funds flow per share decreased to \$0.14 per share for 2002 versus \$0.23 per share in 2001. The weighted average number of shares outstanding in 2002 increased 10 percent to 19,526,269.

Effective January 1, 2002 the Company prospectively adopted the new Canadian accounting recommendations with respect to accounting for stock based compensation. The Company has elected to continue to account for its stock based compensation plan for directors, officers and employees using the intrinsic value method. No options were granted in 2002 to directors, officers or employees. Stock options awarded to consultants are accounted for under the fair value based method utilizing assumptions as disclosed in the notes to the financial statements.

Under the fair value method, an amount of \$3,211 was recorded as a non cash general and administrative expense resulting in contributed surplus in 2002.

Depletion and depreciation is determined on the unit of production method based on total proven reserves (using prices and costs at the balance sheet date) with natural gas converted to a barrel equivalence using six thousand cubic feet equal to one barrel. Non-producing properties are excluded from depletion and depreciation calculations and future development costs of proven undeveloped reserves are included in depletion and depreciation calculations. The cost of non-producing properties excluded from the calculation at December 31, 2002 were \$1,452,000 (2001 – \$860,000) attributable to 45,500 net acres of undeveloped land at year end. Future development costs of undeveloped reserves increased to \$959,000 from \$587,000 reflecting projects in progress at year end.

Depletion and depreciation increased to \$9.90 per BOE in 2002 compared to \$6.76 per BOE in 2001. Depletion and depreciation increased, on a per unit basis, due to a higher depletable base combined with the effect of negative reserve revisions. The provision for future abandonment and site restoration costs, included in depletion and depreciation, increased to \$0.35 per BOE from \$0.28 per BOE in 2001 as a result of the increased number of producing wells in 2002. The provision for future abandonment and site restoration is determined by management in consultation with the Company's engineers and is based on prevailing regulations, costs, technology and industry standards. The total future liability is estimated at \$656,000 at December 31, 2002 (2001 – \$520,000). Current expenditures for abandonment and site restoration of producing properties were nil.

The future income tax provision for 2002 decreased to approximately \$32,000 (\$896,000 in 2001) due to the decrease in pretax income. The Company has approximately \$6.3 million of tax pools remaining at December 31, 2002 and, depending on commodity prices, may be taxable on a current basis in 2003.

Net income decreased by 75 percent to \$0.5 million versus \$1.9 million in 2001 primarily as a result of lower natural gas prices, higher operating costs and increased depletion charges. Net income per share decreased 82 percent to \$0.02 per share versus \$0.11 per share in 2001.

Liquidity and Capital Resources

Capital expenditures of \$5.5 million were financed through a combination of cash flow, working capital and the proceeds from the issue of common shares. The Company issued 1,666,666 common shares through a private placement in the fourth quarter of 2002 for gross proceeds of \$1.5 million. The issue was composed of half flow-through common shares and half non flow-through common shares. The total outstanding common shares were 21,028,552 at December 31, 2002.

At December 31, 2002 the Company had a working capital deficiency of approximately \$781,000 and unutilized bank facilities. The current bank facilities are \$3.6 million subject to the annual

review of current activities and reserves. The 2003 capital budget has been approved at eight million and will be funded through a combination of cash flow and utilization of credit facilities. The Board of Directors reviews the capital budget throughout the year and adjusts it as justified by economic potential and financing capacity.

Business Risks

Exploration, development and production of petroleum and natural gas involve many risks that even the combination of experience and careful evaluation may not be sufficient to overcome. Utilizing highly skilled professionals, focusing in areas where the Company has existing knowledge and expertise or access to such expertise, using up to date technology, and controlling costs to maximize margins, mitigate these risks. The Company maintains a comprehensive insurance program that insures liability and property consistent with industry practice. The program is designed to mitigate risks and protect against significant loss. However, the Company is not fully insured against all these risks, nor are all such risks insurable.

Financial risks include exposure to fluctuation in commodity prices, currency exchange rates, and interest rates. To mitigate commodity risk, the Company maintains direct marketing control over its production. The Company enters into physical contracts for the sale of natural gas at fixed prices and terms and currently has fixed pricing arrangements as disclosed earlier. Although not currently utilized, the Company may institute financial hedging techniques for interest rates, currency exchange rates and commodity prices. If utilized, such transactions would be subject to certain limits on term and amount as established by the Board of Directors.

Supplementary Information

Net Asset Value

	2002		2001	
	Discounted at		Discounted at	
(\$ thousands, except per share)	10%	12%	10%	12%
Net present value of reserves, before income taxes **	18,293	17,438	15,274	14,319
Value of undeveloped land*	1,926	1,926	2,014	2,014
Working capital (deficiency)	(781)	(781)	549	549
Net asset value**	19,438	18,583	17,837	16,882
Net asset value per share**	\$0.92	\$0.88	\$0.92	\$0.87

* Based on independent appraisals at January 1, 2003 and 2002

** Excludes the value of proprietary seismic and other assets.

+ Probable reserve value has been reduced by 50 percent to account for risk.

++ 21,028,552 shares outstanding at December 31, 2002 (2001:19,361,886)

MANAGEMENT'S REPORT

The accompanying financial statements and all information in the Annual Report are the responsibility of management. The financial statements have been prepared by management in accordance with the accounting policies in the notes to the financial statements. When necessary, management has made informed judgments and estimates in accounting for transactions which were not complete at the balance sheet date. In the opinion of management, the financial statements have been prepared within acceptable limits of materiality, and are in accordance with Canadian generally accepted accounting principles (GAAP) appropriate in the circumstances. The financial information elsewhere in the Annual Report has been reviewed to ensure consistency with that in the financial statements.

Management has prepared Management's Discussion and Analysis (MD & A). The MD & A is based upon the Company's financial results prepared in accordance with Canadian GAAP. The MD & A compares the audited financial results for the twelve months ended December 31, 2002 to December 31, 2001.

Management maintains appropriate systems of internal control. Policies and procedures are designed to give reasonable assurance that transactions are properly authorized, assets are safeguarded and financial records properly maintained to provide reliable information for the preparation of financial statements.

KPMG LLP, an independent firm of Chartered Accountants, was engaged, as approved by a vote of shareholders at the Company's most recent annual general meeting, to audit the financial statements in accordance with generally accepted auditing standards in Canada and provide an independent professional opinion.

The Audit Committee of the Board of Directors has discussed the financial statements, including then notes thereto, with management and external auditors. The financial statements have been approved by the Board of Directors on the recommendations of the Audit Committee.



Laurie Smith
President & CEO
April 7, 2003



Sharon Supple
Chief Financial Officer

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the balance sheets of Raven Energy Ltd. as at December 31, 2002 and 2001 and the statements of income and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2002 and 2001 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepting accounting principles.

KPMG LLP

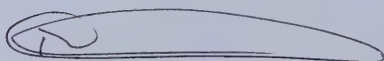
Chartered Accountants
Calgary, Canada
April 7, 2003

BALANCE SHEETS

December 31	2002	2001
Assets		
Current assets		
Cash and term deposits	\$ 63,846	\$ 2,144,115
Accounts receivable	1,018,578	2,268,561
Prepaid expenses and deposits	144,679	198,838
	1,227,103	4,611,514
Petroleum and natural gas properties (note 2)	13,979,161	10,607,361
	\$ 15,206,264	\$ 15,218,875
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	\$ 2,007,671	\$ 4,062,016
Future abandonment and site restoration costs	146,100	67,300
Future income taxes (note 4)	3,419,310	3,087,485
Shareholders' equity		
Share capital (note 5)	6,455,949	5,290,306
Retained earnings	3,177,234	2,711,768
	9,633,183	8,002,074
	\$ 15,206,264	\$ 15,218,875

See accompanying notes to financial statements.

Approved on behalf of the Board



David H. Erickson
Director



John D.G. van der Lee
Director

STATEMENTS OF INCOME AND RETAINED EARNINGS

<i>Years ended December 31</i>	2002	2001
Revenue		
Petroleum and natural gas	\$ 5,298,076	\$ 6,228,073
Royalties, net of ARTC	(961,801)	(1,277,861)
Interest income	9,511	61,680
	4,345,786	5,011,892
Expenses		
Operating	1,192,317	739,858
General and administrative	349,767	195,967
Interest	62,336	—
Depletion and depreciation	2,238,740	1,286,400
	3,843,160	2,222,225
Income before income taxes	502,626	2,789,667
Income taxes (note 4)		
Current	5,465	4,667
Future	31,695	896,266
	37,160	900,933
Net income	465,466	1,888,734
Retained earnings, beginning of year	2,711,768	823,034
Retained earnings, end of year	\$ 3,177,234	\$ 2,711,768
Earnings per share – basic and diluted	\$ 0.02	\$ 0.11
Weighted average number of common shares outstanding	19,526,269	17,801,749

See accompanying notes to financial statements.

STATEMENTS OF CASH FLOWS

Years ended December 31	2002	2001
Cash provided by (used in):		
Operating activities		
Net income	\$ 465,466	\$ 1,888,734
Items not involving cash:		
Stock based compensation (note 5[d])	3,211	—
Depletion and depreciation	2,238,740	1,286,400
Future income taxes	31,695	896,266
Funds flow from operations	2,739,112	4,071,400
Change in non-cash working capital	312,036	325,960
	3,051,148	4,397,360
Financing activities		
Issue of share capital, net of issuance costs	1,462,562	3,343,409
Change in non-cash working capital	10,036	—
	1,472,598	3,343,409
Investing activities		
Petroleum and natural gas properties	(5,531,740)	(7,817,608)
Change in non-cash working capital	(1,072,275)	895,716
	(6,604,015)	(6,921,892)
Increase (decrease) in cash and term deposits	(2,080,269)	818,877
Cash and term deposits, beginning of year	2,144,115	1,325,238
Cash and term deposits, end of year	\$ 63,846	\$ 2,144,115
<i>See accompanying notes to financial statements.</i>		
Supplemental cash flow information:		
Cash received (paid) during the year for:		
Interest income	\$ 10,511	\$ 60,680
Interest expense	\$ (52,300)	\$ —
Income taxes	\$ 145,638	\$ (152,320)

Years ended December 31, 2002 and 2001

Raven Energy Ltd. (the "Company") was incorporated under the Business Corporations Act (Alberta) on June 15, 1998. The principal business activity of the Company is the exploration, development and production of petroleum and natural gas in Alberta.

1. SIGNIFICANT ACCOUNTING POLICIES:

The financial statements of Raven Energy Ltd. (the "Company") have been prepared by management in accordance with Canadian generally accepted accounting principles. The principal accounting policies followed by the Company are summarized below:

(a) Petroleum and natural gas properties:

(i) *Petroleum and natural gas properties*

The Company follows the full cost method of accounting for petroleum and natural gas operations whereby all costs of exploring for and developing petroleum and natural gas reserves are capitalized and accumulated in a single cost center representing the Company's activity undertaken exclusively in Canada. Such costs include land acquisition costs, geological and geophysical expenses, lease rental costs on non-producing properties, costs of drilling both productive and non-productive wells, related plant and production equipment costs, and administration costs directly related to these activities.

The provision for depletion and depreciation is determined on the unit-of-production method based on the estimated gross proven reserves as determined by independent engineers. Petroleum and natural gas reserves and production are converted into equivalent units based upon relative energy content. Costs associated with the acquisition and evaluation of significant unproved properties are excluded from amounts subject to depletion until such times as the properties are proved or become impaired.

The capitalized costs less accumulated depletion and depreciation are limited to an amount equal to the estimated future net revenue from proven reserves (based on prices and costs at the balance sheet date) plus the unimpaired cost of non-producing properties less estimated future administrative expenses, development costs, financing costs and income taxes.

Proceeds from the sales of petroleum and natural gas properties are applied against capitalized costs, with no gain or loss recognized, unless such a sale would significantly alter the rate of depletion and depreciation.

(ii) *Future abandonment and site restoration costs*

Estimated future abandonment and site restoration costs are provided for over the life of the proven reserves on a unit-of-production basis. Costs are estimated each year by management in consultation with the Company's engineers based on current regulations, costs, technology and industry standards. The annual charge is included in depletion and depreciation expense and actual abandonment and site restoration expenditures are charged to the accumulated provision account as incurred.

(iii) Joint activities

Substantially all of the exploration and production activities of the Company are conducted jointly with others and accordingly these statements reflect only the Company's proportionate interest in such activities.

(b) Income taxes:

The Company follows the liability method of accounting for future income taxes. Under the liability method, future income tax assets and liabilities are determined based on "temporary differences" (differences between the accounting basis and the tax basis of the assets and liabilities), and are measured using the currently enacted, or substantively enacted, tax rates and laws expected to apply when these differences reverse. Income tax expense is the sum of the Company's provision for current income taxes and the difference between opening and ending balances of the future income tax assets and liabilities.

(c) Flow-through shares:

The Company has financed a portion of its petroleum and natural gas exploration activities with flow-through share issues. The exploration and development expenditures funded by flow-through share expenditures are renounced to investors in accordance with tax legislation. The estimated value of the tax pools foregone is reflected as a reduction in share capital with a corresponding increase in future income taxes.

(d) Stock based compensation:

The Company has an equity incentive plan, which is described in Note 5 (d).

Effective January 1, 2002 the Company has prospectively adopted the new Canadian accounting policies with respect to accounting for stock options. The Company has elected to continue to account for its stock based compensation plan for directors, officers and employees using the intrinsic value method. Under the intrinsic value method, compensation costs are not recognized in the financial statements for stock options when issued at market value. Any consideration received on exercise of the stock options is credited to share capital.

In accordance with the new accounting policies, stock option awards to consultants are accounted for under the fair value based method, and such awards result in a compensation expense in the period that the benefit relates to.

(e) Per share amounts:

Basic per share amounts are calculated using the weighted average number of common shares outstanding during the year. Diluted per share amounts are calculated based on the treasury stock method, which assumes that any proceeds obtained on the exercise of options would be used to purchase common shares at the average market price during the period. The weighted average number of shares outstanding is then adjusted by the net change.

(f) Measurement uncertainty:

The amounts recorded for depletion and depreciation of property, plant and equipment and the provision for future abandonment and site restoration costs are based on estimates. The ceiling test is based on such factors as estimated proven reserves, production rates, petroleum and natural gas prices and future costs. By their nature, these estimates are subject to measurement uncertainty and changes in these estimates may impact the financial statements of future periods.

(g) Financial instruments:

The Company periodically uses certain financial instruments to hedge its exposure to commodity price fluctuation on a portion of its petroleum and natural gas sales. Gains and losses on these transactions are reported as adjustments to revenue when the related production is sold.

2. PETROLEUM AND NATURAL GAS PROPERTIES:

	2002	2001
Petroleum and natural gas properties, at cost	\$ 17,789,465	\$ 12,257,725
Accumulated depletion and depreciation	3,810,304	1,650,364
	<u>\$ 13,979,161</u>	<u>\$ 10,607,361</u>

Costs of unproved properties excluded from costs subject to depletion and depreciation at December 31, 2002 were approximately \$1,452,000 (2001 – \$860,000). Future development costs of proven undeveloped reserves of \$959,000 (2001 – \$587,000) were included in costs subject to depletion and depreciation.

Estimated future abandonment and site restoration costs to be accrued over the remaining life of the proved reserves are approximately \$510,000 (2001 – \$453,000).

3. BANK FACILITY:

The Company has access to a demand revolving facility of \$3,600,000 from a Canadian chartered bank. The credit facility bears interest at bank prime rate plus 0.75% per annum and is secured by a general security agreement constituting a first ranking security interest in all personal property and a first ranking charge on all real property. As at December 31, 2002, the line of credit was unutilized.

4. INCOME TAXES:

- (a) The provision for income taxes differs from the amounts which would be obtained by applying the combined federal and provincial income tax rate as follows:

	2002	2001
Income tax rate	42.12%	42.62%
Expected income tax provision	\$ 211,706	\$ 1,188,956
Increase (decrease) in taxes resulting from:		
Non-deductible crown payments	206,369	315,287
Resource allowance	(313,066)	(482,065)
Alberta Royalty Tax Credit	(41,234)	(62,139)
Future tax rate reduction	(36,221)	(65,757)
Large corporation tax	5,465	4,667
Other	4,141	1,984
	<u>\$ 37,160</u>	<u>\$ 900,933</u>

- (b) The components of the Company's net future income tax liability at December 31, 2002 and 2001 are as follows:

	2002	2001
Petroleum and natural gas properties	\$ (3,488,434)	\$ (3,125,057)
Future abandonment and site restoration	46,153	21,512
Share issue costs	22,971	16,060
	<u>\$ (3,419,310)</u>	<u>\$ (3,087,485)</u>

5. SHARE CAPITAL:

(a) Authorized:

The authorized share capital consists of an unlimited number of common shares and an unlimited number of preferred shares, issuable in series. No preferred shares have been issued.

(b) Common shares issued:

	Number of Shares	Amount
Share capital, December 31, 2000	17,036,886	\$ 2,656,910
Issued on exercise of stock options	25,000	2,500
Private placements for cash	2,300,000	3,350,000
Tax effect of flow-through shares	—	(713,885)
Share issue costs	—	(9,091)
Tax effect of share issue costs		3,872
Share capital, December 31, 2001	19,361,886	\$ 5,290,306
Private placements for cash	1,666,666	1,500,000
Tax effect of flow-through shares	—	(315,900)
Share issue costs	—	(37,438)
Tax effect of share issue costs		15,770
Share capital, December 31, 2002	21,028,552	\$ 6,452,738
Contributed surplus, December 31, 2002	—	3,211
Balance, December 31, 2002	21,028,552	\$ 6,455,949

(c) Private placements:

On November 25, 2002 the Company completed a private placement of 833,333 units at a price of \$1.80 per unit for gross proceeds of \$1,500,000. Each unit consisted of one common share and one flow-through common share. Directors and officers of the Company subscribed for 164,145 units for consideration of \$295,461. Total flow-through share issues during the year were \$750,000 which the Company is committed to spend on qualifying expenditures by December 31, 2003.

During 2001, the Company completed two private placements. On July 4, 2001 the Company completed a private placement of 750,000 units at a price of \$2.60 per unit, for gross proceeds of \$1,950,000. Each unit consisted of one common share and one flow-through common share. Directors and officers of the Company subscribed for 115,000 units for consideration of \$299,000. On December 28, 2001 the Company completed a private placement of 400,000 units at a price of \$3.50 per unit for gross proceeds of \$1,400,000. Each unit consisted of one common share and one flow-through common share. Directors and officers of the Company subscribed for 95,700 units for consideration of \$334,950.

(d) Stock option plan:

The Company has a stock option plan authorizing the grant of options to acquire shares to designated participants (being directors, officers, employees or consultants). Under terms of the plan the Company may grant options to acquire a maximum number of shares equal to ten percent of the total issued and outstanding shares of the Company. The aggregate number of options that may be granted to any one individual must not exceed five percent of the total issued and outstanding shares. Options are granted at exercise prices equal to

the market value of the shares at the date of grant and are granted for a five year term. Options granted to officers and directors vest immediately. The vesting periods for options granted to employees and consultants are determined by the Board at the time of the specific grant.

The following table summarizes the changes in the Company's stock option plan:

	2002		2001	
	Number of Options	Weighted average exercise price	Number of Options	Weighted average exercise price
Outstanding at the beginning of year	775,000	\$0.56	575,000	\$0.21
Granted	50,000	\$0.80	225,000	\$1.39
Exercised	—	—	(25,000)	\$0.10
Forfeited	(25,000)	\$1.29	—	—
Outstanding at the end of year	800,000	\$0.55	775,000	\$0.56
Options exercisable at year end	750,000	\$0.53	750,000	\$0.53

The following table summarizes information about the stock options outstanding at December 31, 2002:

Range of Exercise Prices	Options Outstanding			Options Exercisable	
	Number Outstanding	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
\$0.10-0.49	550,000	0.9	\$0.22	550,000	\$0.22
\$0.50-0.99	50,000	4.8	\$0.80	0	\$0.00
\$1.00-1.50	200,000	3.5	\$1.40	200,000	\$1.40
\$0.10-1.50	800,000	1.8	\$0.55	750,000	\$0.53

During the year ended December 31, 2002 the Company did not grant any options to directors, officers or employees. The fair value of options granted to consultants during the year ended December 31, 2002 were estimated on the date of grant using the Black Scholes option-pricing model with the following weighted average assumptions: zero dividend yield, expected volatility of fifty percent, risk-free interest rates of four percent and expected life of five years. The weighted average fair market value of options granted to consultants in 2002 was \$0.39 per option, of which \$3,211 has been recognized in 2002 as compensation expense and contributed surplus.

On January 8, 2003 the Company granted 400,000 options to officers and directors and 50,000 options to a consultant to the Company. The options are exercisable at a price of \$1.00 per share and expire five years from the date of the grant.

(e) Shares in escrow:

At December 31, 2002, 816,170 (2001 – 4,174,522) common shares issued and outstanding are held in escrow and shall be released based on various time and performance criteria with written consent of various regulatory authorities.

6. RISK MANAGEMENT:

(a) Interest rate risk:

The Company is exposed to interest rate fluctuations on any outstanding bank indebtedness.

(b) Credit risk:

A substantial portion of the Company's accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. Purchasers of the Company's petroleum and natural gas are subject to an internal credit review to minimize the risk of non-payment.

(c) Commodity risk:

The Company has a price risk management program whereby the commodity price associated with a portion of its future production is fixed. The Company has entered into fixed priced sales contracts for a portion of its future natural gas production resulting in an average contracted volume of 1.8 million cubic feet per day for the period January 1, 2003 to August 31, 2003 at a weighted average contract price of \$5.90 per thousand cubic feet.

(d) Fair value of financial instruments:

Financial instruments of the Company consist of cash and term deposits, accounts receivable, prepaid expenses and deposits, accounts payable, and accrued liabilities. At December 31, 2002 there are no significant differences between the carrying value of such instruments reported on the balance sheet and their estimated market value.

CORPORATE INFORMATION

Directors

David H. Erickson
J. Reid Hutchinson*
Laurie J. Smith*
John D.G. van der Lee*

Officers

Laurie J. Smith
President & CEO
Sharon A. Supple
Chief Financial Officer
David H. Erickson
Vice-President, Operations
Daniel G. Kolibar
Secretary

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*Member, Audit Committee

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Calgary, Alberta

Banker

Royal Bank Of Canada
Calgary, Alberta

Transfer Agent & Registrar

CIBC Mellon Trust Company of Canada
Calgary, Alberta

Auditors

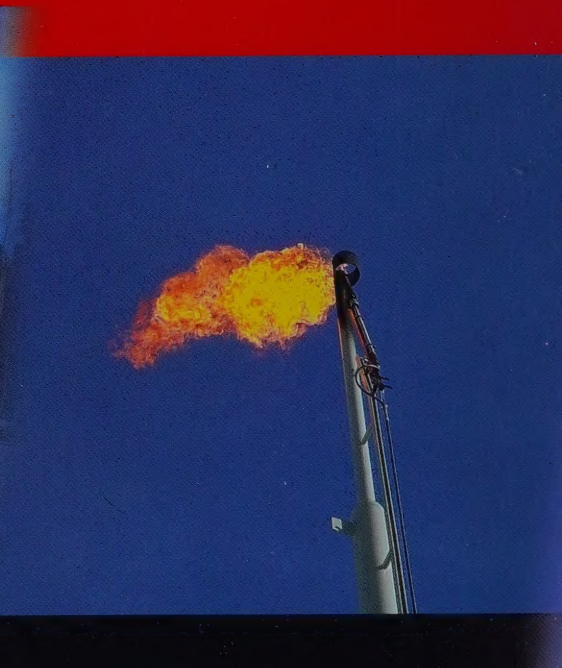
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Canadian Venture Exchange
Common Share Symbol: **RVL**

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